COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY
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STATEMENT OF LEGAL AND FACTUAL BASIS

Virginia Electric and Power Company
Southampton Power Station
Franklin, Virginia
Permit No. TRO-61093

Title V of the 1990 Clean Air Act Amendments required each state to develop a permit program to ensure that certain facilities have federal Air Pollution Operating Permits, called Title V Operating Permits. As required by 40 CFR Part 70 and 9 VAC 5 Chapter 80, Virginia Electric and Power Company has applied for a Title V Operating Permit for its Southampton Power Station. The Department has reviewed the application and has prepared a draft Title V Operating Permit.

Permit Writer / Contact: _____ Date: **August 29, 2013**
Kelly R. Giles
(757) 518-2155

Regional Air Permits Manager: _____ Date: **August 29, 2013**
Troy D. Breathwaite

Regional Director: _____ Date: **August 29, 2013**
Maria R. Nold

Attachments:
Engineering Analysis for 05/23/2012 PSD permit – Attachment A

I. FACILITY INFORMATION

Permittee
Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Facility
Southampton Power Station
30134 General Thomas Highway
Franklin, Virginia 23851

County-Plant Identification Number: 51-175-00051

SOURCE DESCRIPTION
NAICS Numbers 221117

The Southampton Power Station (SPS) is an electric generating facility that produces electricity for Dominion. The Station includes two biomass-fired stoker boilers, each with a maximum rated capacity of 394 MMBtu/hr, with associated fuel, lime, and ash handling systems, as well as several small diesel engine sources used to provide redundant or backup capability. No. 2 fuel oil is used for startup of the biomass boilers. One oil-fired auxiliary boiler is located at SPS to provide steam to the host during times when the Station is not generating electricity.

Before this current Title V permit modification, the facility was a Title V major source of SO_2, NO_x and CO. This source is located in a designated PSD area for all pollutants (9 VAC 5-20-205) and is a PSD major source. The facility is currently permitted under a PSD permit issued on May 23, 2012.

This significant modification to SPS's Title V permit is to incorporate the changes made in the modification of SPS approved in the PSD permit dated May 23, 2012. The PSD modification address conversion of the site's two primary boilers (001 and 002) from coal fired units to units fired on woody biomass as defined in the permit.

II. COMPLIANCE STATUS

A full compliance evaluation of this facility, including a site visit, has been conducted. In addition, all reports and other data required by permit conditions or regulations, which are submitted to DEQ, are evaluated for compliance. Based on these compliance evaluations, the facility has not been found to be in violation of any state or federal applicable requirements at this time.

III. EMISSION UNIT AND CONTROL DEVICE IDENTIFICATION

The emissions units at this facility consist of the following:

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity *	Pollution Control Device Description (PCD)	PCD ID	Pollutant Controlled	Applicable Permit Date
Fuel Burning Equipment / Utility Units							
001	001	PrimaryBiomass Boiler to generate steam for process use and electricity. (No. 2 fuel oil for start-up only) (2012)	394 MMBTU/hour	SNCR Dry Lime Scrubber Fabric Filter Baghouse	EC-1a EC-1b EC-1c	NO_x SO_2 PM/PM-10/PM-2.5 Metals	05/23/12 PSD
002	001	PrimaryBiomass Boiler to generate steam for process use and electricity. (No. 2 fuel oil for start-up only) (2012)	394 MMBTU/hour	SNCR Dry Lime Scrubber Fabric Filter Baghouse	EC-2a EC-2b EC-2c	NO_x SO_2 PM/PM-10/PM-2.5 Metals	05/23/12 PSD
004	004	Auxiliary Boiler to produce steam for process use (combusts No. 2 fuel oil)	81.58 MMBTU/hour (nominal)	Low NO_x Burners	EC-4	NO_x	05/23/12 PSD
006	006	Emergency Auxiliary Diesel Generator	1.4 MMBTU/hour 410 kW (nominal)	N/A	N/A	N/A	05/23/12 PSD
007	007	Emergency Diesel Feedwater Pump	1.23 MMBTU/hour 126 BHP (nominal)	N/A	N/A	N/A	05/23/12 PSD
008	008	Diesel Firewater Pump Engine	0.68 MMBTU/hour 208 BHP (nominal)	N/A	N/A	N/A	05/23/12 PSD
009	009	Portable Diesel Air Compressor Engine	0.49 MMBTU/hr 80 BHP (nominal)	N/A	N/A	N/A	05/23/12 PSD

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity *	Pollution Control Device Description (PCD)	PCD ID	Pollutant Controlled	Applicable Permit Date
Biomass, Ash, and Lime Handling							
010	010	Biomass Storage Silo	180 tons	Bin Vent Filter	EC-10	PM/PM-10/PM-2.5	05/23/12 PSD
011 012 013	011 012 013	Boiler Ash Conveyor Blower Systems (A, B and C)	28 tons/hr each	Fabric Filter Baghouse	EC-11 EC-12 EC-13	PM/PM-10/PM-2.5	05/23/12 PSD
014	014	Recycle Ash Storage	26.5 tons/hr	Bin Vent Filter			
015	015	Ash Storage Silo	530 tons	Bin Vent Filter	EC-15	PM/PM-10/PM-2.5	05/23/12 PSD
016	FUGITIVE	Ash Unloading Feeder	80 tons/hr	Ash Conditioning System - water spray	EC-16	PM/PM-10/PM-2.5	05/23/12 PSD
017	017	Pebble Lime Storage Silo	135 tons	Bin Vent Filter	EC-17	PM/PM-10/PM-2.5	05/23/12 PSD
101A 101B	FUGITIVE	Biomass Truck Tippers (2) to Receiving Hoppers (2)	269 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
101C	FUGITIVE	Emergency Reclaimer	90 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
102	FUGITIVE	Biomass Storage Pile	3×10^6 ft^3	N/A	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
103	FUGITIVE	Biomass Stacker	269 tons/hr	N/A	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
104-1 104-2	FUGITIVE	Truck Tipper Reclaimer (#1 and #2) to Conveyor A Transfer Point	269 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
104-3	FUGITIVE	Conveyor B to Diverter Gate #2 Transfer Point	269 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
104-4	FUGITIVE	Conveyor C to Stacker Transfer Point	269 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
104-5	FUGITIVE	Reclaimer to Conveyor D Transfer Point	269 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
104-6	FUGITIVE	Emergency Reclaimer to Conveyor D Transfer Point	269 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity *	Pollution Control Device Description (PCD)	PCD ID	Pollutant Controlled	Applicable Permit Date
Biomass, Ash, and Lime Handling (Cont'd)							
104-7	FUGITIVE	Diverter Gate #2 to Conveyor D Transfer Point	269 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
104-8	FUGITIVE	Conveyor D to Conveyor E Transfer Point	269 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD
104-9	FUGITIVE	Conveyor E to Fuel Bunker Drag Chain Transfer Point	269 tons/hr	Partial Enclosure	N/A	PM/PM-10/PM-2.5	05/23/12 PSD

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.

IV. EMISSIONS INVENTORY

A copy of the 2012 annual emission update is attached. Emissions are summarized in the following tables.

2012 Criteria Pollutant Emissions in Tons/Year					
Emission Unit	**VOC**	**CO**	**SO2**	**PM10**	**NOx**
Primary Boiler (001)	0.359	7.983	28.100	1.284	174.900
Primary Boiler (002)	0.228	3.466	24.600	1.142	160.700
Auxiliary Boiler (004)	0.004	0.105	0.507	0.048	0.403
Diesel Generators and Pumps (006, 007, 008 and 009)	0.002	0.007	0.002	0.002	0.033
Coal Handling (010a-i)				0.500	
Ash Handling (011-017)				1.169	
Total	**0.593**	**11.561**	**53.209**	**4.145**	**336.036**

2012 Hazardous Air Pollutant Emissions in Tons/Year	
Pollutant	**Tons/yr**
Total Non-VOC/Non-PM10 HAPs	0.61

V. EMISSION UNIT APPLICABLE REQUIREMENTS - (001, 002 and 004)

A. Limitations - All Boilers (001, 002 and 004)

The following Virginia Administrative Codes that have specific emission requirements have been determined to be applicable:

9 VAC 5-80-490	Article 3: Permit Content
9 VAC 5-80-1180	Article 6: Standards and conditions for granting permits
9 VAC 5-50-260	Article 4: (Rule 5-4) Standards for stationary sources
9 VAC 5-50-410	Article 5: (Rule 5-5) Designated standards of performance
9 VAC 5-50-280	Article 4: (Rule 5-4) Standard for major stationary sources (prevention of significant deterioration areas)

The following Federal Regulations that have specific emission requirements have been determined to be applicable:

40 CFR 60	NSPS Subpart Db
40 CFR 60	NSPS Subpart Dc
40 CFR 64	Compliance Assurance Monitoring

See also PSD permit issued 05/23/12.

The emission limits for the allowable combined operation of the primary boilers and the auxiliary boiler are revised to match the "after biomass conversion" operating conditions of the primary boilers.

Visible emissions limit for the boilers is lowered from 10%/27% to 10%/20%.

B. Limitations - Auxiliary Boiler (004)

The following Virginia Administrative Codes that have specific emission requirements have been determined to be applicable:

9 VAC 5-80-490	Article 3: Permit Content
9 VAC 5-80-1180	Article 6: Standards and conditions for granting permits
9 VAC 5-50-260	Article 4: (Rule 5-4) Standards for stationary sources
9 VAC 5-50-280	Article 4: (Rule 5-4) Standard for major stationary sources (prevention of significant deterioration areas)

The following Federal Regulations that have specific emission requirements have been determined to be applicable:

40 CFR 60	NSPS Subpart Dc
40 CFR 63	MACT Subpart DDDDD

See also PSD permit issued 05/23/12.

The significant modification to the PSD permit issued on May 23, 2012 to convert the two primary boilers from coal to biomass fired units did not affect the requirements of the auxiliary boiler.

The applicability of 40 CFR 63 Subpart DDDDD (Boiler MACT) and it's requirements were added to this section.

C. Limitations - Primary Boilers (001 and 002)

The following Virginia Administrative Codes that have specific emission requirements have been determined to be applicable:

9 VAC 5-80-490	Article 3: Permit Content

The following Federal Regulations that have specific emission requirements have been determined to be applicable:

40 CFR 60	NSPS Subpart Db

40 CFR 63 MACT Subpart DDDDD

See also PSD permit issued 05/23/12.

Due to the change in fuel from coal to woody biomass, the specified control efficiency for SO_2 is removed since there is a substantial reduction in potential to emit of SO_2 (e.g. ~6,000 tpy reduction in uncontrolled SO_2 emissions). See Attachment A for discussion.

In order to support the PSD emission calculations, the maximum hourly firing rate and the annual total heat input of the primary boilers are limited.

Emissions limits of the primary boilers are revised to match the "after biomass conversion" operating conditions.

The applicability of 40 CFR 63 Subpart DDDDD (Boiler MACT) and it's requirements were added to this section.

D. Monitoring – All Boilers (001, 002 and 004)

The following Virginia Administrative Codes that have specific monitoring requirements have been determined to be applicable:

9 VAC 5-80-490 Article 3: Permit Content

The following Federal Regulations that have specific monitoring requirements have been determined to be applicable:

40 CFR 60 NSPS Subpart Db
40 CFR 60 NSPS Subpart Dc

See also PSD permit issued 05/23/12.

E. Monitoring – Auxiliary Boiler (004)

The following Virginia Administrative Codes that have specific monitoring requirements have been determined to be applicable:

9 VAC 5-80-490 Article 3: Permit Content

The following Federal Regulations that have specific monitoring requirements have been determined to be applicable:

40 CFR 60 NSPS Subpart Dc

See also PSD permit issued 05/23/12.

F. Monitoring – Primary Boilers (001 and 002)

The following Virginia Administrative Codes that have specific monitoring requirements have been determined to be applicable:

9 VAC 5-80-490	Article 3: Permit Content

The following Federal Regulations that have specific monitoring requirements have been determined to be applicable:

40 CFR 60	NSPS Subpart Db
40 CFR 64	Compliance Assurance Monitoring
40 CFR 72	Acid Rain Program
40 CFR 73	Acid Rain Allowances
40 CFR 75	Acid Rain Program Monitoring Requirements

See also PSD permit issued 05/23/12.

Previous PSD and T5 permits required CEMS both before and after the SO_2 inlet and outlet of the spray dryer to comply with the then applicable NSPS Da SO_2 percent reduction requirement. The current PSD permit issued May 23, 2012, requires only an SO_2 CEM at the outlet of the control device, which will be used to determine compliance with the SO_2 3-hour rolling average emission standard. The now applicable NSPS Db requires only a CEM after the control device and there are no percent reduction requirements after the biomass conversion.

CAM (40 CFR 64) applies to an emissions unit at a major stationary source, which is required to have a T5 permit if the unit:

1. Is subject to an emission limit or standard;
2. Uses a control device to meet the emission limit;
3. Has uncontrolled emissions greater than the major source threshold (100 tpy).

Each of the primary boilers has its own NO_x CEM and the permit requires that these monitors be used to determine compliance with the emission standard. Therefore, these monitors meet the Part 64 definition of a "continuous compliance determination method" and in accordance with 40 CFR 2(b)(vi) the requirements of CAM do not apply to them.

Both the underlying PSD and the current draft T5 permits require that PM emissions from the primary boilers be controlled, principally by a lime-water spray dryer and a fabric filter system and that a series of quarterly initial stack tests for PM be formed while the units are combusting biomass. A COM system for the primary boilers was required previously and continuous to be required. Also, continuous exhaust gas temperature monitoring between the spray dryer and the baghouse inlet provides assurance that the lime-water injection system is operating. Therefore, assuming that the test of the primary boilers show compliance with the PM limits, site specific data will be available to demonstrate what the concurrent exhaust gas temp and opacity are expected to be during compliant operation. Furthermore, typical failures of fabric filter systems are immediately obvious in terms of opacity. Therefore, the exhaust gas temp monitoring system and the COM system are considered "to provide a reasonable assurance of compliance with the emission limits" as specified in 40 CFR 64.3 and their use is adequate to meet the requirements of CAM.

G. Recordkeeping

The following Virginia Administrative Codes that have specific recordkeeping requirements have been determined to be applicable:

9 VAC 5-80-490	Article 3: Permit Content
9 VAC 5-60-50	Notification, records and reporting
9 VAC 5-50-50	Notification, records and reporting
9 VAC 5-80-1180	Article 6: Standards and conditions for granting permits

The following Federal Regulations that have specific emission requirements have been determined to be applicable:

40 CFR 60	NSPS Subpart Db
40 CFR 60	NSPS Subpart Dc
40 CFR 64	Compliance Assurance Monitoring

See also PSD permit issued 05/23/12.

H. Testing

The following Virginia Administrative Codes that have specific testing requirements have been determined to be applicable:

9 VAC 5-80-490	Article 3: Permit Content

The following Federal Regulations that have specific emission requirements have been determined to be applicable:

40 CFR 60	NSPS Subpart Db

See also PSD permit issued 05/23/12.

Initial stack tests for SO_2, NO_x, CO, VOC, Sulfuric Acid Mist and Fluorides are required.

Four "quarterly" initial stack tests are required for each of the following: filterable PM, total PM, filterable PM-10, total PM-10 and total PM2.5; including concurrent fuel quality analyses and visible emissions evaluations (by Method 9 or COM).

I. Reporting

The following Virginia Administrative Codes that have specific reporting requirements have been determined to be applicable:

9 VAC 5-80-490	Article 3: Permit Content
9 VAC 5-50-50	Special Provisions - Notifications, records and reporting
9 VAC 5-50-410	Article 5: (Rule 5-5) Designated standards of performance

The following Federal Regulations that have specific emission requirements have been determined to be applicable:

40 CFR 64	Compliance Assurance Monitoring

See also PSD permit issued 05/23/12.

Prior to the biomass conversion project, the primary boilers were coal fired and therefore subject to NSPS Da. The units are no longer subject to NSPS Da and those reporting requirements are removed from the permit. (See the Streamlined section of this document for more information.)

VI. FUEL BURNING EQUIPMENT REQUIREMENTS - (006, 007, 008 and 009)

A. Limitations

The following Virginia Administrative Codes that have specific emission requirements have been determined to be applicable:

9 VAC 5-80-490	Article 3: Permit Content
9 VAC 5-80-1180	Article 6: Standards and conditions for granting permits
9 VAC 5-50-260	Article 4: (Rule 5-4) Standards for stationary sources
9 VAC 5-50-410	Article 5: (Rule 5-5) Designated standards of performance
9 VAC 5-50-280	Article 4: (Rule 5-4) Standard for major stationary sources (prevention of significant deterioration areas)

See also PSD permit issued 05/23/12.

The significant modification to the PSD permit on 05/23/2012 to convert the two primary boilers (001 and 002) from burning coal as a fuel to burning woody biomass did not affect the requirements of the emergency diesel engines.

B. Recordkeeping

The following Virginia Administrative Codes that have specific recordkeeping requirements have been determined to be applicable:

9 VAC 5-50-50	Special Provisions - Notifications, records and reporting
9 VAC 5-60-50	Special Provisions - HAPs - Notifications, records and reporting
9 VAC 5-80-490	Article 3: Permit Content

See also PSD permit issued 05/23/12.

C. Testing

The following Virginia Administrative Codes that have specific testing requirements have been determined to be applicable:

9 VAC 5-50-20 Special Provisions - Compliance
9 VAC 5-80-490 Article 3: Permit Content

See also PSD permit issued 05/23/12.

The permit contains no requirements to perform testing for Unit Ref. Nos. 006, 007, 008, and 009. The Department and EPA have authority to require testing not included in this permit if necessary to determine compliance with an emission limit or standard.

No reporting requirements have been established for Unit Ref. Nos. 006, 007, 008, and 009.

VII. BIOMASS, ASH & LIME HANDLING REQUIREMENTS - (010a-i and 011 - 017)

A. Limitations

The following Virginia Administrative Codes that have specific emission requirements have been determined to be applicable:

9 VAC 5-80-490 Article 3: Permit Content
9 VAC 5-80-1180 Article 6: Standards and conditions for granting permits
9 VAC 5-50-260 Article 4: (Rule 5-4) Standards for stationary sources

See also PSD permit issued 05/23/12.

The emission unit description and air pollution control equipment references for biomass have replaced the references for coal.

The fugitive dust emissions from the furnace bottom ash drag, the boiler ash collection drag and the mechanical collector ash collection drag are controlled by water spray nozzles.

The reporting required by NSPS Y, coal preparation and processing, does not apply to this biomass facility and has been removed.

B. Monitoring

The following Virginia Administrative Codes that have specific monitoring requirements have been determined to be applicable:

9 VAC 5-80-490 Article 3: Permit Content

See also PSD permit issued 05/23/12.

C. Recordkeeping

The following Virginia Administrative Codes that have specific monitoring requirements have been determined to be applicable:

9 VAC 5-80-490 Article 3: Permit Content
9 VAC 5-50-50 Special Provisions - Notifications, records and reporting

See also PSD permit issued 05/23/12.

D. Testing

The following Virginia Administrative Codes that have specific monitoring requirements have been determined to be applicable:

9 VAC 5-80-490 Article 3: Permit Content

VIII. Facility Wide Conditions

A. Requirements

The following Virginia Administrative Codes that have specific monitoring requirements have been determined to be applicable:

9 VAC 5-80-490 Article 3: Permit Content

See also PSD permit issued 05/23/12.

IX. Streamlined Requirements

In their letter dated 2/21/12, EPA Region III concluded that "…NSPS Da will no longer apply to this operation [the primary boilers] as wood (biomass), under Section 60.40Da, is not considered, and not defined, as a fossil fuel but Subpart Db will apply…" As discussed in this section of the SOB, generally compliance with the standards that resulted from the PSD process insures compliance with the NSPS Db applicable requirements and therefore the NSPS requirements are "streamlined out" of the current Title V permit. (In accordance with the current guidance, citation of the NSPS requirement is included in the relevant T5 condition.) In several cases noted below, applicable requirements from NSPS Db are explicitly added to the current T5 permit.

SO_2 Standards - (NSPS 60.42b) - Biomass combustion at SPS is not subject to SO_2 standards. Biomass is not among the fuels for which there are SO_2 emission limits in 60.42b(a) through (d) and since the biomass potential SO_2 emission rate is less than 0.32 lb/MMBtu, the primary boilers are exempt from the percent reduction requirements in 60.42b(k).

The allowable oil for the primary boilers fits the NSPS Db definition of Very Low Sulfur Oil (VLSO). For units that fire VLSO, the only NSPS Db applicable requirements are the reporting and recordkeeping requirements of 40 CFR 40.49b(r). Citation of 40 CFR 60.42b is included where appropriate.

PM Standards – (NSPS 60.43b) – The PM limit that resulted from the PSD review is 0.019 lb/MMBtu which the most stringent limit in NSPS Db is 0.085 lb/MMBtu. Also, opacity from the PSD review is 10%/20% while the NSPS requirement is 20%/27%. Citation of 60.43b is included where appropriate.

NO_x Standards – (NSPS 60.44b) – The NO_x limit that resulted from the PSD review is 0.135 lb/MMBtu while the most stringent limit for biomass combustion in NSPS Db is 0.2 lb/MMBtu. Citation of 40 CFR 60.44b is included where appropriate.

The primary boilers allowable startup fuel is distillate oil and the startup up burner is 27.5 MMBtu/hr. The minimum statement of the rated capacity is 379 MMBtu/hr; with the resulting effective annual capacity factor for fossil fuel ~7% (i.e. 27.5/379). Per NSPS 60.44b, units with an annual capacity factor less than 10% are not subject to the subpart NO_x standards.

SO_2 Compliance and testing - (NSPS 60.45b) – Since biomass combustion is not subject to and 60.42b SO_2 standards, it follows that there are no compliance and testing requirements for this fuel.

For units that fire only VLSO, there are no compliance and testing requirements. Citation of 40 CFR 60.45b is included where appropriate.

PM and NO_x Compliance and testing – (NSPS 60.46b) – PM/opacity – compliance with the PSD condition to perform the four quarterly initial performance tests for PM insures compliance with the NSPS Db PM testing requirements in 40 CFR 60.46b(b). Citation of 40 CFR 60.46b is included where appropriate.

Compliance with the PSD conditions for concurrent initial Visible Emissions Evaluations (VEE) insure compliance with the opacity testing requirements in 40 CFR 60.46b(d)(7). Citation of 40 CFR 60.46b for opacity is included where appropriate.

NO_x Compliance with the PSD requirement to have a NO_x CEM system for the primary boilers insures compliance with the NSPS Db NO_x compliance methods and procedures requirements in 40 CFR 60.46b(b). Citation of 40 CFR 60.46b for NOx is included where appropriate.

SO_2 monitoring - (NSPS 60.47b) – The allowable fuel oil for the primary boilers fits the NSPS Db definition of Very Low Sulfur Oil (VLSO), the only NSPS Db applicable requirements are the reporting and recordkeeping requirements of 40 CFR 40.49b(r). Citation of 40 CFR 60.47b is included where appropriate.

PM & NO_x monitoring - (NSPS 60.48b) - PM Compliance with the PSD requirement to have a COM system for the primary boilers (001 and 002) insures compliance with the NSPS Db PM monitoring requirements in 40 CFR 60.48b(a) for sources subject to the opacity standard. Citation of 40 CFR 60.48b for PM is included where appropriate.

NO_x Compliance with the PSD requirement to have a NO_x CEM system for the primary boilers insures compliance with the NSPS Db NO_x monitoring requirements in 40 CFR 60.48b(b). Citation of 40 CFR 60.48b for NO_x is included where appropriate.

Reporting & Recordkeeping - (NSPS 60.49b) - 60.49b(a) requires that an affected facility must submit notification of initial startup. Compliance with the PSD notification requirements insures compliance with the 60.49b(a) requirement. Citation of 40 CFR 60.49b for this notification is included where appropriate.

60.49b(b) requires submittal of (1) (NSPS required) initial performance test data and (2) CEM performance evaluation data. At SPS, NSPS initial performance tests are required for PM and NO_x, and in both cases the PSD condition requires submittal of the test results. Similarly, performance evaluations are required for all continuous monitoring systems and the PSD condition requires submittal of the performance evaluation reports. Citation of 40 CFR 60.49b for these submittals is included where appropriate.

60.49b(d) requires records of the amounts of each fuel combusted each day. Compliance with the PSD recordkeeping requirements insures compliance with the 60.49b(d) requirement. Citation of 40 CFR 60.49b for these is included where appropriate.

60.49b(o) requires all records required by NSPS Db to be maintained for 2 years. The current PSD permit requires records to be kept for 5 years. Citation of 40 CFR 60.49b for these is included where appropriate.

60.49b(r) requires demonstration that fuel combusted meets the definition of VLSO. Compliance with the PSD recordkeeping requirements insures compliance with the 60.49b(r) requirement. Citation of 40 CFR 60.49b is included where appropriate.

60.49b(w) specifies the NSPS Db reporting period to be 6 months. Compliance with the general duty requirement to report excess emissions quarterly for continuous monitoring systems used directly for compliance determinations insures compliance with the 60.49b(w) requirement.

The following NSPS Db applicable reporting and recordkeeping requirements have been added to Title V permit.
Reports

- 60.49b(h) => an affected facility shall submit excess emissions reports for opacity and NO_x
- 60.49b(i) => an affected facility shall report the steam generating unit operating day data required to be recorded under 60.49b(g)

Records

- 60.49b(f) => an affected facility subject to the opacity standard shall maintain records of opacity
- 60.49b(g) => an affected facility subject to the NO_x standards shall maintain records of specified data for each steam generating unit operating day

X. GENERAL CONDITIONS

The permit contains general conditions required by 40 CFR Part 70 and 9 VAC 5-80-110 that apply to all Federal-operating permitted sources. These include requirements for submitting semi-annual monitoring reports and an annual compliance certification report. The permit also requires notification of deviations from permit requirements or any excess emissions.

1. Comments on General Conditions

   a. Condition B. Permit Expiration

   This condition refers to the Board taking action on a permit application. The Board is the State Air Pollution Control Board. The authority to take action on permit application(s) has been delegated to the Regions as allowed by §2.2-604 and §10.1-1185 of the *Code of Virginia*, and the "Department of Environmental Quality Agency Policy Statement No. 3-2006".

   b. Condition F. Failure/Malfunction Reporting

   Section 9 VAC 5-20-180 requires malfunction and excess emission reporting within four hours of discovery. Section 9 VAC 5-80-250 of the Title V regulations also requires malfunction reporting; however, reporting is required within two days. Section 9 VAC 5-20-180 is from the general regulations. All affected facilities are subject to section 9 VAC 5-20-180 including Title V facilities. Section 9 VAC 5-80-250 is from the Title V regulations. Title V facilities are subject to both sections. A facility may make a single report that meets the requirements of 9 VAC 5-20-180 and 9 VAC 5-80-250. The report must be made within four daytime business hours of discovery of the malfunction.

   c. Condition J. Permit Modification

   This general condition cites the sections that follow:
   9 VAC 5-80-50. Applicability, Federal Operating Permit For Stationary Sources
   9 VAC 5-80-190. Changes to Permits.
   9 VAC 5-80-260. Enforcement.
   9 VAC 5-80-1100. Applicability, Permits For New and Modified Stationary Sources
   9 VAC 5-80-1790. Applicability, Permits For Major Stationary Sources and Modifications Located in Prevention of Significant Deterioration Areas
   9 VAC 5-80-2000. Applicability, Permits for Major Stationary Sources and Major Modifications Locating in Nonattainment Areas

   d. Condition U. Malfunction as an Affirmative Defense

   The regulations contain two reporting requirements for malfunctions that coincide. The reporting requirements are listed in sections 9 VAC 5-80-250 and 9 VAC 5-20-180. The malfunction requirements are listed in General Condition U and General Condition F. For further explanation see the comments on general condition F.

e. Condition Y. Asbestos Requirements

The Virginia Department of Labor and Industry under Section 40.1-51.20 of the Code of Virginia also holds authority to enforce 40 CFR 61 Subpart M, National Emission Standards for Asbestos.

This general condition contains a citation from the Code of Federal Regulations that follow:
40 CFR 61.145, NESHAP Subpart M. National Emissions Standards for Asbestos as it applies to demolition and renovation.
40 CFR 61.148, NESHAP Subpart M. National Emissions Standards for Asbestos as it applies to insulating materials.
40 CFR 61.150, NESHAP Subpart M. National Emissions Standards for Asbestos as it applies to waste disposal.

XI. CAIR

Although the legal status of CAIR is currently in flux, agency guidance is that CAIR is currently the appropriate applicable emission trading program.

XII. STATE ONLY APPLICABLE REQUIREMENTS

The following Virginia Administrative Codes have specific requirements only enforceable by the State and have been identified as applicable by the applicant:

Odor (9 VAC 5 Chapter 40, Article 2)

State toxics rule (9 VAC 5 Chapter 60)

XIII. INAPPLICABLE REQUIREMENTS

Compliance with the provisions of this permit shall be deemed compliance with all applicable requirements in effect as of the permit issuance date as identified in this permit. This permit shield covers only those applicable requirements covered by terms and conditions in this permit and the following requirements which have been specifically identified as being not applicable to this permitted facility:

Citation	Title of Citation	Description of Applicability
40 CFR 60 Subpart D	Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	No emissions sources at this facility are subject to these NSPS requirements.
40 CFR 60 Subpart Da	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	
40 CFR 60 Subpart K	Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and prior to May 19, 1978	
40 CFR 60 Subpart Ka	Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and prior to July 23, 1984	
40 CFR 60 Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	
40 CFR 60 Subpart Y	Standards of Performance for Coal Preparation and Processing Plants	
There are no applicable GHG permitting requirements.		

Nothing in this permit shield shall alter the provisions of §303 of the federal Clean Air Act, including the authority of the administrator under that section, the liability of the owner for any violation of applicable requirements prior to or at the time of permit issuance, or the ability to obtain information by the administrator pursuant to §114 of the federal Clean Air Act, (ii) the Board pursuant to §10.1-1314 or §10.1-1315 of the Virginia Air Pollution Control Law or (iii) the Department pursuant to §10.1-1307.3 of the Virginia Air Pollution Control Law.
(9 VAC 5-80-140)

XIV. INSIGNIFICANT EMISSION UNITS

The insignificant emission units are presumed to be in compliance with all requirements of the Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping or reporting shall be required for these emission units in accordance with 9 VAC 5-80-110.

Insignificant emission units include the following:

The following emission units at the facility are identified in the application as insignificant emission units under 9 VAC 5-80-720:

Reference No.	Emission Unit Description	Citation	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity 9 VAC 5-80-720 C)
ISU-1	Turbine Lube Oil Reservoir	5-80-720 B.1	VOC	N/A
ISU-2	Water Based (non-solvent)Parts Washer	5-80-720 B.1	VOC	N/A
ISU-3	Used Oil Tank	5-80-720 C.2.a	VOC	500 gallons
ISU-4	Oil/Water Separator (Oil Sump)	5-80-720 C.2.a	VOC	280 gallons
ISU-5	Distillate Oil Storage Tank	5-80-720 C.2.a	VOC	42,000 gallons

These emission units are presumed to be in compliance with all requirements of the federal Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping, or reporting shall be required for these emission units in accordance with 9 VAC 5-80-110.

The citation criteria for insignificant activities are as follows:

9 VAC 5-80-720 A - Listed Insignificant Activity, Not Included in Permit Application
9 VAC 5-80-720 B - Insignificant due to emission levels
9 VAC 5-80-720 C - Insignificant due to size or production rate

XV. CONFIDENTIAL INFORMATION

The permittee did not submit a request for confidentiality. All portions of the Title V application are suitable for public review.

XVI. PUBLIC PARTICIPATION

The proposed permit will be placed on public notice in the Tidewater News newspaper from **Sunday, July 14, 2013** to **Tuesday, August 13, 2013**.

ATTACHMENT A
(Engineering Analysis for 05/23/2012 PSD permit)

PERMIT CHECK LIST

The following people have reviewed the permit:
Reviewing Permitting Engineer: _____
Air Inspector: _____
Air Compliance Manager: _____

Date: July 2, 2013
Source Name: Virginia Electric & Power Company - Dominion Southampton Power Station
Registration No.: 61093 Id. No.: 51-175-00051
Source Location: 30134 General Thomas Highway, Franklin, Virginia 23851
Mail Address: 5000 Dominion Boulevard, Glen Allen, Virginia 23060
Source Status: ____ Greenfield ✓ Currently operating
Source Classification: ___ Minor ___ SynMinor ___ State Major ✓ PSD Major ✓ TV Major
Permit Action: Conversion of primary coal boilers to biomass.

✓ **Inspector Contacted/Consulted**

Permit Action Program:
✓ NSR ___ SOP ___ TV ___ Maj HAP ____ General

Permit Action Type:
___ Exemption
___ New / Article 6 Modification (delete one) ✓ Major Modification
___ Minor Amendment ___Administrative Amendment ___ Renewal
___ State Major ✓ PSD ___ Non-Attainment ___ General Permit

Y (Y/N) Permit Includes All Emission Units at Source.
N (Y/N) Permit Allows Source to avoid Title V/MACT/etc.
After this permit, source is: ✓ Major (A) ___ Minor (B) ___ Synthetic minor (SM)
(NOx, CO, PM and PM_{10} Pollutant)

Permit Application Review
✓ Permit application submitted, or ___ Letter Request
Application Received Date: 5/31/11
Application Complete Date: 3/12/12
Permit Deadline Date: 3/12/13
✓ Document Certification Form received
n/a Confidential information with sanitized copy. If yes, which sections:
___ throughputs ___ individual pollutants ___ flow diagrams ___ calculations
___ process descriptions ___ other (describe)
If yes, has claim been accepted by DEQ? (Y/N) - Date of letter: _____
✓ Copy of letter from local official for greenfield, or major modified sources
✓ Copy of letter sent to FLM if applicable. FLM notified by Mike Kiss – email dated 4/12/11
n/a Notification of Affected State(s)
This permit supersedes permit(s) dated: February 3, 2011 – upon activation of the biomass handling system.

Regulatory Review (cont.)

Regulatory Review

BACT Determination (check one):

__✓__ Good Combustion Practices for the control of __CO__ meets BACT

__See the BACT Analysis Section under Comments for further discussion

___ TV/SOP/BACT not applicable. (Explain)_

__✓__(Y/N) NSPS/MACT/NESHAPS Applicability: If Y, Subpart(s):

__✓__NSPS Subparts Db and Dc

__✓__ MACT Subpart DDDDD

_____ NESHAPS

__N__(Y/N) Existing Rules (9 VAC 5 Chapter 40) Applicability: If Y, Rule(s):

Toxic Pollutants (check one):

___ Exempt, or ___ in compliance with 9 VAC 5-60-320, or __✓__ not evaluated ***(Reminder: remember to change the regulation to 9 VAC 5-60-220 when doing a SOP for existing sources).***

[Comments: _____]

Modeling (check one):

___ Attached (including background monitors), or

__✓__ Copy of approval letter from modeling section,

___ No modeling required by agency policy (< modeling significance levels, etc.)

Site Suitability:

__✓__ Site suitable from an air pollution standpoint, inspection date: 8/2/10, or no inspection required because _____.

__✓__ Calculation sheet(s) attached

__N__(Y/N) NSR Netting Comments (Explain Permit History):

__N__(Y/N) (CAM) Compliance Assurance Monitoring Applicable

Permit includes: __✓__ Stack Testing __✓__ CEM __✓__ VEE by source

Public Participation

__✓__(Y/N) Public Noticed. If yes, Public Notice Date: *Tidewater News*, published on March 16, 2012

__✓__(Y/N) Public Notice Comments. If yes, number and nature of comments: see the Public Response Document attached

__✓__(Y/N) Public Hearing. If yes, Public Hearing Date: April 16, 2012

EPA Review

__✓__(Y/N) EPA Review. If yes, Date proposed permit sent to EPA March 14, 2012.

__✓__(Y/N) EPA Comments. If yes, give a brief summary (see letter dated April 27, 2012)

1) Potential for CO limit reduction pending stack test results.
2) Additional performance tests due to non-uniformity of biomass origins
3) Include method to ensure compliance for sulfuric acid mist and fluoride emissions
4) All reports sent to EPA at listed address
5) Clarify applicability determination in engineering analysis write-up.

Regulatory Review (cont.)
Comments:
Introduction –

Dominion Southampton Power Station (SPS) is located at 30134 General Thomas Highway, Franklin, Virginia. This location is in an attainment area for all pollutants, and the facility is a PSD major source. The facility was previously permitted under a PSD Permit originally issued on November 22, 1989, and amended on November 12, 1992, June 20, 1995, February 6, 1996, December 5, 1996, October 15, 2010 and most recently on February 3, 2011. The facility is also permitted under minor NSR permits dated August 4, 1992, for the auxiliary boiler; November 8, 1993, for a distillate oil-fired boiler; February 20, 2002, for the Phase II Acid Rain permit; August 16, 2002, for the original Title V permit which was subsequently amended on January 12, 2004, to incorporate the provisions of the Phase II Acid Rain permit and the NOx SIP provisions. The January 12, 2004 version of the Title V permit incorporates the February 20, 2002 Phase II Acid Rain permit and the August 16, 2002, Title V permit.

Project Description –

SPS has proposed to convert the 2 primary boilers from coal fired units to 100% biomass fired units. This project also involves modifications to the material handling systems. The coal handling equipment will be abandoned-in-place and new biomass material handling equipment constructed. The SPS facility will be capable of producing 51 MW_{net} of electric power after the conversion. SPS is currently a major source with allowable emissions of SO_x, NO_x and CO above 100 tpy. After the conversion to biomass, permitted emissions from SO_x, NO_x and VOC will decrease while particulate and CO emissions will increase.

For fuel burning equipment, only the primary boilers will be modified by this project. The auxiliary boiler, emergency generator, emergency feedwater pump, emergency firewater pump engine and air compressor engine are not affected.

The biomass for the facility will be obtained from the waste wood of logging and mill operations and also sawdust. Distillate oil will be retained as the start-up fuel for the boilers.

Regulatory Review – Article 6 – Minor NSR

Article 6 applicability is based on the Net Emission Increase (NEI)[1] for the project. NEI compares uncontrolled emissions from the primary boilers firing coal at the permitted throughput (Current Uncontrolled Emissions or CUE) to the uncontrolled emissions firing biomass at 8760 hr/yr (New Uncontrolled Emissions or NUE). NEI = NIE- CUE. If the NEI is less than the modified source exemption rates listed in 9 VAC 5-80-1320 D, then the project is exempt from Article 6 permitting. Calculations are summarized in the following table:

Pollutant (tpy)	NUE - Biomass Uncontrolled @ 8760 hr/yr	CUE - Coal Uncontrolled @ Permit Throughput	NEI	Modified Source Exemption Levels	Article 6/BACT Applicable?
$PM_{2.5}$ total	2133.2	5778.6	-3645.4	n/a[2]	n/a[2]
PM_{10} total	4547.5 *	5778.6	-1231.1	10	No

[1] See VA DEQ Memo APG-354 and APG-354A for additional information.
[2] Article 6 does not address $PM_{2.5}$ emissions.

Regulatory Review (cont.)

Pollutant (tpy)	NUE - Biomass Uncontrolled @ 8760 hr/yr	CUE - Coal Uncontrolled @ Permit Throughput	NEI (tpy)	Modified Source Exemption Levels (tpy)	Article 6/BACT Applicable?
PM total	4898.0	6409.0	-1511.0	15	n/a[3]
SOx	172.6	6447.2	-6274.6	10	No
VOC	44.9	95.5	-50.6	10	No
NOx	776.6	2281.7	-1505.1	10	No
CO	1035.5	636.8	398.8	100	YES
Lead	0.2	509.4	-509.2	0.6	No
Fluorides	3.5	76.4	-73.0	3	No
Sulfuric Acid Mist	4.3	331.1	-326.8	6	No

* - Includes biomass material handling emissions.

As previously mentioned, the proposed project also includes a new biomass fuel handling system. Since this system is new, the current uncontrolled emissions are designated as zero and the new uncontrolled emissions are calculated based on 8760 hours/yr of operation. The biomass fuel handling system is only expected to emit PM, PM_{10} and $PM_{2.5}$. However, the only species of concern for Article 6 is PM_{10} (see footnotes #2 and 3). Dominion's application indicates and DEQ agrees that the uncontrolled emissions from the new biomass fuel handling system are 1.6 tons/yr of PM_{10}. Since this value, both alone and in combination with the decrease in uncontrolled PM_{10} emissions calculated for the primary boilers, is less than the Article 6 exemption level, the proposed project does not trigger Article 6 permitting requirements for any species of particulate matter.

CO is the only pollutant subject to Article 6. However, since CO is subject to major NSR regulations (see the Article 8 section below), CO emissions are exempted from the requirements of Article 6 [4].

Regulatory Review - Article 8 – Major NSR/PSD

For a project to be subject to PSD review it must constitute a major source by itself or occur at an existing major source, cause a Significant Emission Increase (SEI) and cause a Significant Net Emission Increase (SNEI) as these terms are defined in the Article 8 Regulation at 9 VAC 5-80-1615. SPS is currently a PSD major source because it is one of the 28 listed source categories (a fossil fuel-fired steam electric plant capable of more than 250 MMBtu/hr) and has the potential to emit (PTE) greater than 100 tpy of SOx, NOx and CO.

SEI = PAE – BAE and

SNEI = SEI + contemporaneous increases – contemporaneous decreases.

SEI and SNEI calculations are summarized in the following table:

[3] Per 9 VAC 5-80-1320 D.3, a source determined to be exempt for PM_{10}, shall be considered exempt for PM.

[4] Per 9 VAC 5-80-1100 H, the provisions of Article 6 are applicable to sources "...to the extent that such sources and their emission are not subject to the provisions of the major new source review program."

Regulatory Review (cont.)

Pollutant (tpy)	BAE Coal[5]	PAE Biomass[6]	SEI	SNEI	PSD Significant Rates	SEI Significant?	SNEI Significant?
$PM_{2.5}$ total	88.2	98.0	9.9 *	9.9*	10	No	No
PM_{10} total	88.2	102.5	14.9 *	14.9 *	15	No	No
PM total	91.3	114.7	24.9 *	24.9 *	25	No	No
SOx	118.0	38.2	-79.8	-79.8	40	No	No
VOC	2.5	42.4	39.9	39.9	40	No	No
NOx	724.4	412.4	-312.0	-312.0	40	No	No
CO	54.6	916.5	861.9	861.9	100	YES	YES
Lead	0.004	0.15	0.1	0.1	0.6	No	No
Fluorides	0.5	3.4	2.9	2.9	3	No	No
Sulfuric Acid Mist	1.2	8.1	6.9	6.9	7	No	No

* - Includes new/modified biomass material handling emissions of 0.1 tpy for $PM_{2.5}$ (total), 0.6 tpy for PM_{10} (total) and 1.5 tpy for PM (total).

Since the SEI and SNEI calculations for CO are above the PSD significance levels, and the project occurs at an existing major source, this project is a major modification. As such, the conversion of the primary boilers from coal-fired to biomass-fired is subject to PSD review for CO and BACT applies (see the BACT Analysis section for further discussion.)

The SEI and SNEI values above for SO_x, NO_x, CO and lead were calculated by comparing the post-change Projected Actual Emissions (PAE) to the Baseline Actual Emissions (BAE). SPS has elected to use potential emissions in place of PAE for these pollutants.

The SEI and SNEI values for PM, PM_{10}, $PM_{2.5}$, VOC, Sulfuric Acid Mist and Fluorides were determined by the following equation:

Baseline actual emissions + the applicable PSD significance levels – 0.1 ton= combined annual limit for both boilers in tpy
For particulate calculations, SEI includes those emissions from the biomass handling equipment in addition to the boilers.

To determine the permit limits, the equation above was further manipulated as follows:

Combined annual limit for both boilers in tpy / 2 = annual emissions for each boiler in tpy

[5] Baseline Actual Emissions (BAE) with boilers firing coal from July 2007 through June 2009.
[6] Predicted Actual Emissions (PAE) with boilers firing biomass, note that Dominion has elected to use potential emissions in place of predicted actuals as stated in the May 2011 application.

Regulatory Review (cont.)

The annual emissions for each boiler were then converted to lbs per hour using 8400 hr/yr as an operating limitation.

Article 8 defines BAE for an existing electric utility steam generating unit as "the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner within the five-year period immediately preceding when the owner begins actual construction of the project. The board will allow the use of a different time period upon a determination that is more representative of normal source operation."

SPS anticipates that construction will begin in July 2012 which means the five-year period would start in July 2007. The initial application dated May 2011 requested the use of a BAE time period from January 2006 through December 2007. This is outside of the five-year period as described above. Further discussions with SPS on this matter resulted in a change to the BAE period[7] which is within the five year standard, July 2007 through June 2009.

All particulate limits contained in the permit are total (i.e. filterable plus condensable) unless explicitly stated otherwise.

BACT Analysis –

The BACT Analysis is a 5 step process performed on a case-by-case basis and is pollutant specific. For SPS, the top-down BACT determination is completed for CO only. CO is generated during the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel.

Step #1: Identify Potentially Feasible Control Options

For SPS, a facility with existing coal-fired stoker boilers, BACT determinations are based on CO controls for stoker-type biomass boilers. Alternatives to stoker-type biomass boilers themselves and controls on alternatives to stoker-type biomass boilers are outside the scope of this project ("redefine the source") and therefore are not considered as part of the BACT analysis[8]. SPS conducted a review of the RACT/BACT/LAER Clearinghouse (RBLC) and included a table of results in their May 2011 application in Appendix C. DEQ-TRO's review of the RBLC database returned the same results as SPS, once the alternatives described above were removed.

SPS listed combustion controls/good combustion practices (GCP) (i.e. an enhanced overfire air (OFA) system) and post-combustion controls (i.e. regenerative thermal oxidation (RTO) or catalytic oxidation) as potential controls for CO.

The enhanced OFA system proposed/designed by the boiler manufacturer (Babcock & Wilcox) is required to provide the optimum combustion characteristics. Where the existing OFA system is capable of 25 – 30% of the total combustion air, the enhanced system can provide ~50% for the biomass. B&W predicts that using the existing OFA would result in CO emissions of 0.8 lb/MMBtu versus the enhanced system at 0.30 lb/MMBtu.

Step #2: Eliminate Technically Infeasible Options

Of the three potential control options listed in Step #1, only the RTO is eliminated as technically infeasible. The application states "RTO technology is normally applied to exhaust streams ...in which the only

[7] See Dominion letter dated January 17, 2012.
[8] See PSD Appeal No. 91-39 by the Environmental Appeals Board.

Regulatory Review (cont.)

contaminant is gaseous organic solvents (i.e. VOC). This technology could potentially be installed downstream of the particulate removal systems for the Southampton biomass boiler conversion. However, all qualified vendors of RTO systems do not recommend this technology due to the potential fouling of the regenerative media… This will result in an unacceptable frequency of forced shutdowns to the operation."

DEQ-TRO has confirmed this issue with RTO's for this particular project. Thermal oxidizers use high temperatures to oxidize CO to CO_2 and water. RTO's are subject to fouling by PM in the flue gas. Therefore the RTO would need to be placed after the PM controls. It is for these reasons, as well as finding no documentation of RTO's used on biomass-fired boilers, that this control option is considered technically infeasible from a practical standpoint and will not be discussed further in this BACT analysis.

Step #3: Rank Remaining Control Options by Control Effectiveness

Baseline emissions are based on emission guarantees from the boiler manufacturer (B&W) and are consistent with the information available in the RBLC.

Control Option	Removal Efficiency	Emission Rate (lb/MMBtu)
Catalytic Oxidation w/ Recuperative Heat Exchangers	> 70 – 90%	< 0.10
Good Combustion Practices	Baseline	0.30

Step #4: Evaluate Economic, Environmental and Energy Impacts

SPS states that the catalytic oxidizer system will result in additional fuel costs for the reheat burner with no increase in the plant's electrical output, as well as pressure drop increase which will require additional internal electricity consumption. The fuel burning to operate the catalytic oxidizer will increase emissions, namely GHG constituents. Additionally, the system would oxidize ammonia slip from the SNCR and residual SO_2 in the flue gas to H_2SO_4. Thus resulting in an estimated increase of 30 tpy of NO_x and 48 tpy of H_2SO_4.

SPS also provided a cost analysis for the catalytic oxidizer with recuperative heat recovery. DEQ-TRO found some minor discrepancies with the analysis supplied and the guidelines typically used. The differences include the use of an 8% interest rate by SPS where EPA uses a 7% interest rate[9]. Also, the control efficiency is listed as having a range of >70 – 90% removal of CO but the evaluation is only conducted at 80% removal. EPA OAQPS guidance states direct installation costs (DIC) is approximated to be 30% of the purchased equipment costs (PEC). SPS estimates the DIC to be roughly equal to the PEC. Further information from SPS[10] illustrates that due to the retrofit nature of this project and actual site conditions (i.e. considerable field work, small footprint, vertical configuration, etc.) the DIC estimates provided are justifiable. Even with these corrections, the $/ton of CO removed is too high at $8043/ton of CO removed.

Step #5: Selection of BACT

The three control options presented were RTO, catalytic oxidation with recuperative heat exchanger and GCP. The RTO was determined to be practically infeasible due to PM fouling and no demonstrated use of an RTO on biomass-fired boilers. Catalytic Oxidation was determined to have an adverse environmental impact (i.e.

[9] EPA applies the current social interest rate used by the White House Office of Management and Budget. Since 1993, this has been set at 7%.

[10] See email dated February 15, 2012.

Regulatory Review (cont.)

emission increases related to the additional fuel burning and ammonia slip and SO_2 oxidation) as well as being cost prohibitive.

Therefore, DEQ-TRO is in agreement that GCP meets BACT. The proposed limit for CO is 0.30 lb/MMBtu.

Regulatory Review – MACT/State Toxics

SPS is a major source of HAPs and as such, the boilers are subject to MACT DDDDD[11]. In accordance with 9 VAC 5-60-300 C, the state toxics regulation does not apply to a facility covered by a MACT. No MACT requirements are included in this permit. Once the status of the Boiler MACT (stay/vacatur/reconsideration) is finalized, the necessary requirements will be included in the Title V permit.

The SPS boilers are not "new" because they were constructed prior to June 4, 2010. This project to retrofit the coal boilers to fire biomass represents about 5% of the cost to construct a new biomass boiler; therefore, these units are subject to the standards for "existing" boilers under the MACT. Based on the application, the units will meet those standards.

Previous permits listed several HAPs under the primary coal boiler emission limit condition (in lb/day limits). These limits have been removed due to the applicability of the Boiler MACT.

Regulatory Review – NSPS

SPS is currently permitted as a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr which is subject to NSPS Subpart Da. EPA has confirmed[12] that NSPS Da will no longer apply to the boilers "…as wood (biomass), under Section 60.40Da, is not considered, and not defined, as a fossil fuel but Subpart Db will apply to these emission sources as they meet the definition of an affected facility under those regulations in Section 60.40b which accounts for all fuels."

Regulatory Review – GHG's

After July 1, 2011, modifications at a facility otherwise subject to PSD with CO_2e emissions greater than 75,000 tpy are subject to PSD review for GHG's. EPA has deferred the applicability of PSD requirements to biogenic CO_2 emissions from bioenergy and other biogenic stationary sources (i.e. electric utilities burning biomass fuels.) Emissions of GHG (i.e., methane and N_2O) for the biomass project (including start-up operations using distillate oil) at SPS are included in the calculations and shown to be 56,395 tpy CO_2e which is less than the 75,000 tons $CO2_e$ /yr threshold. Therefore, GHG from the current project is not subject to PSD review.

SPS has withdrawn the GHG BACT Analysis from its application.[13]

Public Participation –

In accordance with 9 VAC 5-80-1775 A - C, SPS placed an ad in the Tidewater News on July 27, 2011. The informational public briefing was held on September 14, 2011.[14]

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[11] On January 9, 2012, the DC Circuit Court vacated EPA's stay on the Boiler MACT. However, the legal status of the rule itself does not alter the outcome that the SPS boilers are subject to Subpart DDDDD.

[12] See EPA letter dated February 21, 2012, Re: Applicability Determination for Biomass Fuel Change.

[13] See Dominion letter dated February 9, 2012.

Regulatory Review (cont.)

As provided by 9 VAC 5-80-1775 E and F, DEQ placed an ad in the Tidewater News on March 16, 2012. The public comment period ended on April 30, 2012 (15 days after the date of the public hearing). The public hearing was held on April 16, 2012 at 7:00 pm at the Paul D. Camp Community College, Franklin Campus. Fourteen people signed the attendance record, an estimated 16 individuals were present.

Please see the Public Response Document (attached) for a summary of public comments and DEQ responses pertaining to this project.

Modeling -

See the modeling report dated March 9, 2012, for a detailed discussion on air quality impacts.

In summary, the modeled results for CO (1-hour and 8-hour averaging periods) were less than the applicable Significant Impact Levels and are shown below. Additionally, there are no adverse impacts to soils and vegetation and no significant emissions from secondary growth as a result of this project. CO is not one of the pollutants of concern that is evaluated for affecting visibility, and therefore a visibility impairment analysis was not required. Also, there are no PSD increments for CO so a PSD increment analysis was not required.

Pollutant	Averaging Period	Max. Predicted Concentration from Proposed Facility ($\mu g/m^3$)	Class II Significant Impact Level ($\mu g/m^3$)
CO	1-hour	66.4	2,000
	8-hour	36.4	500

All pollutants that affect visibility and acidic deposition (i.e., AQRVs) will decrease as a result of this project. The US Forest Service and National Park Service each stated that they would not require any AQRV analysis for this project.

Aux. Boiler –

The 2/3/11 permit analysis discusses the auxiliary boiler and its hours of operation. Specifically, the auxiliary boiler does not have an annual hourly limit, yet the combined primary and auxiliary boiler emission limit condition mentions the aux. boiler operating at 360 hr/yr. As discussed by email dated January 25, 2011, the reason is "that the auxiliary boiler can be used as a means to provide steam to the Ashland Chemical plant when the main boilers were not operating. As such, the auxiliary boiler would provide the balance of 8760 hr/yr that was not supplied by the main units." With the 2/3/11 coal permit, (and previous permits) the main boilers were limited to a maximum 8400 hr/yr, and consequently, the aux. boiler could operate for 360 hr/yr (total 8760 hr/yr). This hourly assumption (360 hr/yr) for the aux. boiler continues to be used to determine the combined

[14] See Dominion email dated September 17, 2011.

Regulatory Review (cont.)

primary and aux. boiler emissions[15] due to the assertion by SPS that "the two main boilers are the only combustion sources that are proposed to be modified[16]...."

Other Items –

The previous permits contained a condition[17] on boiler operation which stated that the coal boilers "shall be operated at a heat input rate not to exceed the rate at which compliance with emission limits....has been demonstrated by stack emission tests." This condition has been replaced with condition #29, which limits the maximum hourly and total (combined) annual heat input for the biomass boilers. With the old condition, though the "nominal" rating for the boilers might be 400 MMBtu/hr, if stack tests show compliance while firing at a slightly higher rate, then the boilers could continue to fire at the higher rate while calculations and permit limits were determined using the nominal value. The new condition and stack testing requirements will ensure compliance with permitted limits.

The 2/3/11 permit contained limitations for SO_2 based on the combustion of coal. The current requirements are 0.162 lb/MMBtu, 61.3 lb/hr, and flue gas desulfurization with a 92% control efficiency. This switch to biomass reduces the available sulfur (4,000 TPY reduction in uncontrolled emissions) such that review of the limitations is necessary. Reviewing the RBLC for similar facilities, no control efficiency requirements have been found with similar emission limitations. Additionally, recently permitted biomass boilers in Virginia have higher lb/MMBtu limitations (0.017 and 0.06 lb/MMBtu) and no control efficiency requirements. Therefore, the requirements of the proposed permit (flue gas desulfurization meeting at least 0.0125 lb/MMBtu and 4.9 lb/hr) are appropriate.

Final Recommendation: Recommend Approval.

Environmental Engineer's Signature: _____

Air Permit Manager's Signature: _____

[15] See Condition #37 contained in this permit.
[16] Application dated May 2011, section 3.1.
[17] February 3, 2011 permit condition #26.

Registration Number : 61093

County - Plant Id: 175-00051

Plant Name : Dominion - Southampton Power Station

POLLUTANT EMISSIONS REPORT (STACK/POINT) (TONS/YEAR)

Parameter List

Pollutant Type: All Pollutants
Years: 2012 - 2012

Inventory Year 2012

Stack #: 1 Main Boiler #1

Point #: 1	CL	CO	CRC	HCL	HF	NH3	NO2	PB
Segment #: 1 Coal	0.000	7.878	0.252	0.001	0.001	0.005	174.900	0.000
Segmeht #: 2 fuel		0.105				0.017	0.000	0.000
Segment #: 3 tail		0.000					0.000	
	0.000	7.983	0.252	0.001	0.001	0.021	174.900	0.000

Registration Number : 61093

County - Plant Id: 175-00051

Plant Name : Dominion - Southampton Power Station

POLLUTANT EMISSIONS REPORT (STACK/POINT) (TONS/YEAR)

Parameter List

Pollutant Type: All Pollutants
Years: 2012 - 2012

Inventory Year 2012

Stack #: 1

Point #: 1	PM	PM 10	PM 2.5	SEC	SO2	VOC
1	5.038	1.206	0.563	0.183	28.100	0.315
2	0.042	0.048	0.033		0.000	0.004
3	0.000	0.030	0.030		0.000	0.040
	5.080	1.284	0.625	0.183	28.100	0.359

Stack #: 2 Main Boiler #2

Point #: 2	CL	CO	CRC	HCL	HF	NH3	NO2	PB
Segment #: 1 coal	0.000	3.376	0.000	0.001	0.001	0.004	160.700	0.000
Segment #: 2 fuel		0.090				0.014	0.000	0.000
Segment #: 3 tar		0.000					0.000	
	0.000	3.466	0.000	0.001	0.001	0.018	160.700	0.000

Registration Number : 61093

County - Plant Id: 175-00051

Plant Name : Dominion - Southampton Power Station

POLLUTANT EMISSIONS REPORT (STACK/POINT) (TONS/YEAR)

Parameter List

Pollutant Type: All Pollutants
Years: 2012 - 2012

Inventory Year 2012

Stack #: 2

Point #: 2	PM	PM 10	PM 2.5	SEC	SO2	VOC
1	4.631	1.101	0.514	0.167	24.600	0.200
2	0.036	0.041	0.036		0.000	0.004
3	0.000	0.000	0.000		0.000	0.025
	4.667	1.142	0.550	0.167	24.600	0.228

Stack #: 3 Aux. Boiler

Point #: 4	CO	NH3	NO2	PB	PM	PM 10	PM 2.5	SO2
Segment #: 1 fuel oil	0.000		0.000	0.000	0.000	0.000		0.000
Segment #: 2 fuel	0.105	0.017	0.403		0.042	0.048	0.033	0.507
	0.105	0.017	0.403	0.000	0.042	0.048	0.033	0.507

Registration Number : 61093

County - Plant Id: 175-00051

Plant Name : Dominion - Southampton Power Station

POLLUTANT EMISSIONS REPORT (STACK/POINT) (TONS/YEAR)

Parameter List

Pollutant Type: All Pollutants
Years: 2012 - 2012

Inventory Year 2012

Stack #: 3

Point #: 4	VOC
1	0.000
2	0.004
	0.004

Stack #: 4

Point #: 5	CO	NH3	NO2	PB	PM	PM 10	PM 2.5	SO2
Segment #: 1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Registration Number : 61093

County - Plant Id: 175-00051

Plant Name : Dominion - Southampton Power Station

POLLUTANT EMISSIONS REPORT (STACK/POINT) (TONS/YEAR)

Parameter List

Pollutant Type: All Pollutants
Years: 2012 - 2012

Inventory Year 2012

Stack #: 4

Point #: 5	VOC
1	0.000
	0.000

Stack #: 6 Gens + Pumps

Point #: 6	CO	NO2	PM 10	PM 2.5	SO2	VOC
Segment #: 1	0.007	0.033	0.002	0.002	0.002	0.002
	0.007	0.033	0.002	0.002	0.002	0.002

Stack #: 7 Coal Handling

Point #: 7	PM 10	PM 2.5
Segment #: 1	0.500	0.500
	0.500	0.500

Stack #: 8 Ash Handling

Point #: 8	PM 10	PM 2.5
Segment #: 1	0.815	0.815
Segment #: 2	0.001	0.001
Segment #: 3	0.001	0.001
Segment #: 4	0.151	0.151
Segment #: 5	0.202	0.202
	1.169	1.169

Registration Number: 61093

County - Plant ID: 175-00051

Plant Name: Dominion - Southampton Power Station

POLLUTANT EMISSIONS REPORT (PLANT) (Tons/Year)

Parameter List

Pollutant Type: Hazardous Pollutants

Years: 2012 -2012

	CL	CRC	HCL	HF	SEC
2012	0.000	0.252	0.002	0.002	0.351

Total HAPS:
0.61